BEFORE THE

PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-224-E
DOCKET NO. 2019-225-E

In the Matter of: South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC	)))))))))	**DIRECT TESTIMONY OF DEWEY S. ROBERTS II ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dewey S. Roberts II (Sammy) and my business address is 3401 Hillborough Street, Raleigh, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy as General Manager, Transmission Planning and Operations Strategy.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES AS GENERAL MANAGER, TRANSMISSION PLANNING AND OPERATIONS STRATEGY.

A. I have primary responsibility for the development of long-term strategy for Transmission Planning and Operations. This includes long-term planning to support transmission system transformation needed to enable coal plant retirements and to integrate replacement generation resources. This responsibility also includes developing strategies and standards for transformed system operations necessary to reliably operate the Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP," together with DEC, the "Companies" or "Duke Energy") power systems to facilitate a smooth transition through planned coal plant retirements and increasing amounts of renewable energy resources and storage.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from North Carolina State University in 1987 with a Bachelor of Science Degree in Electrical Engineering. I also obtained a Master of Science Degree in Electrical

Engineering from North Carolina State University in 1990 and a Master of Business Administration Degree from North Carolina State University in 2004. I am also a registered Professional Engineer in the state of North Carolina, and I am recognized as a Certified System Operator by the North American Electric Reliability Corporation.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I joined Duke Energy in 1990 and have held several engineering and management positions in Nuclear Engineering, Engineering and Technical Services, System Operator Training, Portfolio Management, Transmission Services, and System Operations. These positions include: Project Engineer, Manager - Transmission Services, and Manager - Power System Operations, Director – System Operations, and General Manager – System Operations. In July 2020, I assumed the position of General Manager, Transmission Planning and Operations Strategy.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION") OR ANY OTHER UTILITY COMMISSION?

A. Yes. I have testified before this Commission and the North Carolina Utilities Commission ("NCUC") on several occasions in the Progress Energy Carolinas annual fuel proceedings.

Q. ARE YOU INCLUDING ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide an overview of the grid-related analysis and investment, especially transmission investment, associated with the six scenarios discussed in DEC's and DEP's Integrated Resource Plan ("IRP"). In Chapter 7 of the IRPs filed by

DEC and DEP, we describe the development of initial cost estimates for grid requirements to enable the retirement of coal generating units and associated replacement generation for the six key portfolios presented in the IRPs and which are discussed by Witness Snider. Various other portions of the IRPs contain grid-related information and assumptions. While my testimony provides an overview, the best source for our plans and assumptions remains in the comprehensive IRP planning documents filed on behalf of DEC and DEP on September 1, 2020. The sections that I reference are part of the Companies' compliance with the filing requirements of Act 62, particularly S.C. Code Ann. §§ 58-37-40(B)(1)(d)(g) and (i).[1]

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Retiring existing coal facilities that support the grid and integrating incremental resources forecasted in the IRPs will require significant investment in the transmission systems of DEC and DEP. As described in Chapter 11 and Appendix A of the DEC and DEP IRPs, if replacement generation that can provide similar ancillary services, as well as real power needs, is not located at the site of the retiring coal facility, transmission investments will generally be required to accommodate the unit's retirement in order to maintain regional grid stability. Furthermore, a range of additional transmission network upgrades will be required depending on the type and location of the replacement generation being interconnected with the grid. I explain the nature of these projects and associated costs below as they relate to the various scenarios proposed in the IRPs. Those scenarios, "Base

[1] S.C. Code Ann. §§ 58-37-40(B)(1) provides at subsection (d) [that a utility shall file] "a summary of the electrical transmission investments planned by the utility"; at subsection (g) [that a utility shall file "plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan"; and at subsection (i) [that a utility shall file] ",,,actions the utility proposes to take in order to achieve…peak reduction."

without Carbon Policy", "Base with Carbon Policy", "Earliest Practicable Coal Retirement", "70% CO_2 Reduction: High Wind", "70% CO_2 Reduction: SMR", and "No New Gas Generation", are introduced by Witness Snider.

I also explain that the current constitution of the Companies' grid is not set up for the realities of future power flows and customer usage patterns, which is addressed throughout the IRPs and discussed by Witness Snider. I highlight a few of the technologies necessary for the grid to meet the demands of tomorrow in my testimony, such as battery storage and voltage control systems.

Finally, the NCUC has required particular studies be addressed by the Companies, and due to the system nature of the operations of DEC and DEP, those studies are filed with these IRPs not only for transparency but also to align the IRPs' results between the two states.

II. GRID REQUIREMENTS' COST ASSOCIATED WITH IRP PORTFOLIOS

Q. WHAT IS THE TRANSMISSION INVESTMENT ASSOCIATED WITH THE IRP PORTFOLIOS?

A. Tables 1 and 2 below provide a summary of the coal plant retirement MWs, incremental resource MWs, and the estimated transmission network upgrade costs for each of the DEC and DEP IRP portfolios.

Table 1 - DEC IRP Portfolio Incremental Resources and Associated Transmission Costs

DEC IRP Scenario ⊕ / Resource Type	Base w/o CO2 Policy	Base with CO2 Policy	Earliest Practicable	70% Reduction in CO2 (Wind)	70% Reduction in CO2 (SMR)	No New Gas
Coal Retirements	-3754MW	-3754 MW	-5974 MW	-5974 MW	-5974 MW	-5974 MW
Incremental Solar	2720 MW	4970 MW	4970 MW	7478 MW	7478MW	7478 MW
Incremental Gas	4276 MW	3052 MW	5647 MW	4276 MW	3966 MW	0 MW
Storage ⊞	351 MW	595 MW	595 MW	2404 MW	2404 MW	2406 MW
Onshore Wind	0 MW	150MW	0 MW	1101 MW	1101 MW	1401MW
Offshore Wind	0 MW	0 MW	0 MW	1338 MW	138 MW	138 MW
SMR	0 MW	0 MW	0 MW	0 MW	684 MW	684 MW
Transmission	$600M	$1.0B	$700M	$4.3B	$2.1B	$2.7B

⊕ Combined forecasted and model-selected incremental additions by the end of 2035.
⊞ Includes Standalone Storage, Storage at Solar plus Storage sites, and Pumped Storage Hydro.

Table 2 - DEP IRP Portfolio Incremental Resources and Associated Transmission Costs

DEP IRP Scenario ⊕ / Resource Type	Base w/o CO2 Policy	Base with CO2 Policy	Earliest Practicable	70% Reduction in CO2 (Wind)	70% Reduction in CO2 (SMR)	No New Gas
Coal Retirements	-3208 MW	-3208 MW	-3208 MW	-3208 MW	-3208 MW	-3208 MW
Incremental Solar	2000 MW	3425 MW	3500 MW	4835 MW	4835 MW	4985 MW
Incremental Gas	5337 MW	4276 MW	3966 MW	2138 MW	2138 MW	0 MW
Battery Storage ⊞	698 MW	1593 MW	1595 MW	2010 MW	2010 MW	5011 MW
Onshore Wind	0 MW	600 MW	1350 MW	1729 MW	1729 MW	1729 MW
Offshore Wind	0 MW	0 MW	0 MW	1292 MW	92 MW	2492 MW
SMR	0 MW	0 MW	0 MW	0 MW	684 MW	0 MW
Transmission	$400M	$800M	$700M	$3.2B	$1.0B	$6.2B

⊕ Combined forecasted and model-selected incremental additions by the end of 2035.
⊞ Includes Standalone Storage and Storage at Solar plus Storage sites.

Q. WHAT SIMPLIFYING ASSUMPTIONS WERE MADE RELATED TO THE IRPs AND GRID REQUIREMENTS?

A. Cost estimates were developed for network upgrade needs associated with coal plant retirements as well as network upgrade costs for incremental MW resources based on three scenarios: “Base Case with Carbon Policy”, “70% CO_2 Reduction: High Wind”, and “70% CO_2 Reduction: No New Gas Generation” in both IRPs. The cost estimates for these three scenarios yielded network upgrade unit costs ($/MW) for various incremental resources including solar, solar plus storage, stand-alone storage, onshore wind, gas generation, and small modular reactors in both IRPs. Where resource specific studies were available, i.e. North Carolina Transmission Planning Collaborative (“NCTPC”) offshore wind study, estimated costs for transmission upgrade projects identified in the study as necessary to enable integrating the specific resource were used. In addition to adding incremental resources to the DEC and DEP systems, the Companies conducted a high-level assessment to identify transmission projects and estimated costs associated with increasing import capability into the DEC/DEP area transmission systems from all neighboring transmission regions as well as from offshore wind. The import capability assessments considered the necessary new construction and upgrades needed to increase import capability by 5GW and 10GW respectively.

Q. PLEASE DEFINE TERMS NECESSARY TO EXPLAIN WHAT GRID REQUIREMENT COSTS WERE ESTIMATED IN THE IRPs TO ENABLE INTERCONNECTION OF INCREMENTAL RESOURCES.

A. The key terms are described below:

<u>Distribution Upgrades</u>: The additions, modifications, and upgrades to the Utility's Distribution System at or beyond the Point of Interconnection to facilitate Interconnection of the Generating Facility and render the service necessary to allow the Generating Facility to operate in parallel with the Utility and to inject electricity onto the Utility's System. Distribution Upgrades do not include Interconnection Facilities.

<u>Interconnection Facilities</u>: Collectively, the Utility's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Utility's System. Interconnection Facilities are sole use facilities and shall not include Upgrades.

<u>Network Upgrades</u>: Additions, modifications, and upgrades to the Utility's Transmission System required to accommodate the Interconnection of the Generating Facility to the Utility's System. Network Upgrades do not include Distribution Upgrades.

<u>Point of Interconnection</u>: The point where the Interconnection Facilities connect with the Utility's System.

<u>Upgrades</u>: The required additions and modifications to the Utility's System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Q. BASED ON THE DEFINITIONS PROVIDED, EXPLAIN THE GRID REQUIREMENTS' COSTS ESTIMATED AND INCLUDED IN THE IRPs.

A. Figure 1 below provides a good representation of the types of Network Upgrades for which grid requirements costs were estimated for integrating a portfolio resource based on resource type, MW size and year of resource addition, if a study for that specific resource type and projected resource location had not been previously performed. Costs for Distribution Upgrades or Interconnection Facilities were not included since these costs are usually the responsibility of the generation customer seeking interconnection and thus would not impact transmission customer rates.

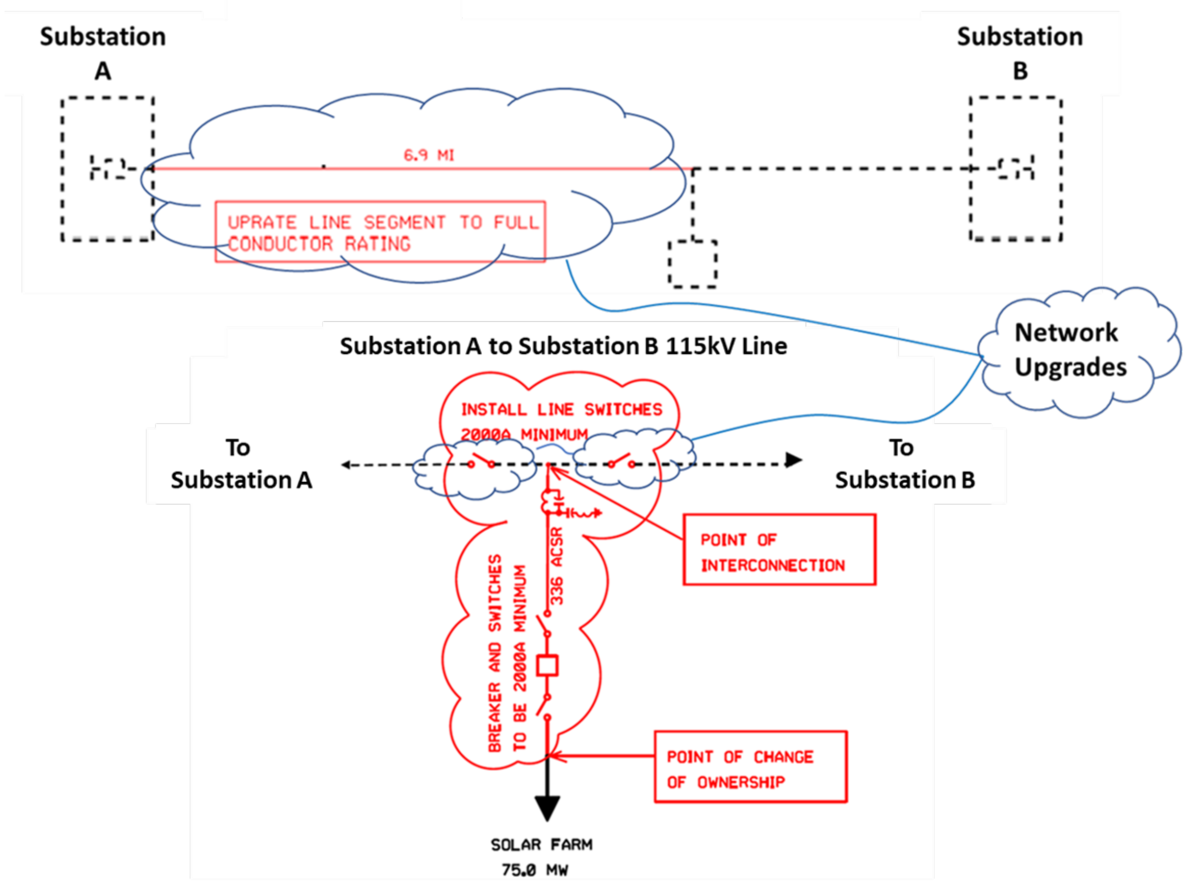

Figure 1 – Network Upgrades Associated with Interconnecting 75MW Solar Facility

Q. PLEASE DESCRIBE DEC's AND DEP's FUTURE TRANSMISSION PROJECTS REQUIRED TO FACILITATE THE RESOURCES IDENTIFIED IN THE IRPs.

A. The six portfolios presented in the IRPs included different assumptions for coal plant retirement dates along with a varying array of demand and supply-side resource requirements to reliably serve load over the planning horizon. High-level assessments were conducted to estimate the associated necessary transmission network upgrades for retiring the existing coal facilities and integrating each scenario's requisite incremental resources, including combinations of some or all of the following resources: solar, solar-plus-storage hybrid facilities, stand-alone battery storage, pumped-hydro generation/storage, onshore wind, offshore wind, increased off-system purchases, and dispatchable natural gas facilities. These assessments were conducted at a high level utilizing several reasonable, simplifying assumptions as described earlier. To the extent possible, the Companies used recent interconnection studies as a basis for future costs. Extensive additional study and analysis of the complex interactions regarding future resource planning decisions will be needed over time to better quantify the cost of transmission system upgrades associated with any portfolio.

Q. PLEASE DESCRIBE DEC's FUTURE TRANSMISSION PROJECTS TO FACILITATE RETIREMENT OF EXISTING DEC COAL FACILITIES.

A. The high-level assessment conducted to determine the transmission network upgrades needed to enable the retirement of the DEC coal facilities without replacing generation on site was estimated to be:

- Marshall 1-4: $200 million
- Belews Creek 1&2: $230 million

These estimated network upgrade costs reflect new Static VAR Compensators (SVCs), line upgrades, and new substation equipment. These network upgrades such as a new SVC, 230kV/115kV transformer, or upgrading the conductor size on a transmission line would serve to alleviate voltage and power flow issues identified in system impact studies.

Q. PLEASE DESCRIBE DEP's FUTURE TRANSMISSION PROJECTS TO FACILITATE RETIREMENT OF EXISTING DEP COAL FACILITIES.

A. The high-level assessment conducted to determine the transmission network upgrades needed to enable the retirement of the DEP coal facilities without replacing generation on site was estimated to be:

- Mayo & Roxboro 1-4: $80 million

These estimated network upgrade costs reflect a new Static VAR Compensator (SVC), a new capacitor bank, and new substation equipment. Similar to the DEC network upgrades needed to retire DEC coal units, these network upgrades such as a new SVC, 230kV/115kV transformer, or upgrading the conductor size on a transmission line would serve to alleviate voltage and power flow issues identified in system impact studies.

Q. PLEASE DESCRIBE THE COST AND NATURE OF DEC's AND DEP's FUTURE TRANSMISSION PROJECTS TO FACILITATE THE "BASE CASE WITH CARBON POLICY" PORTFOLIO.

A. DEC: As shown in Table A-12 on page 184 of the DEC IRP, for the Base Case with Carbon Policy portfolio, DEC retires 3,754 MW of coal and adds 4,970 MW of incremental solar, 150 MW of onshore wind, 595 MW of incremental storage, and 3,052 MW of incremental gas resources. The high-level assessment conducted to determine the DEC transmission network upgrades needed to enable the interconnection of these new incremental resources resulted in an estimate of $560 million needed for the upgrades.

DEP: As shown in Table A-12 on page 183 of the DEP IRP, for the Base Case with Carbon Policy portfolio, DEP retires 3,208 MW of coal and adds 3,425 MW of incremental solar, 600 MW of onshore wind, 1,593 MW of incremental storage, and 4,276 MW of incremental gas resources. The high-level assessment conducted to determine the DEP transmission network upgrades needed to enable the interconnection of these new incremental resources resulted in an estimate of $460 million needed for the upgrades.

Q. PLEASE DESCRIBE THE COST AND NATURE OF DEC's AND DEP's FUTURE TRANSMISSION PROJECTS TO FACILITATE THE "70% CO_2 REDUCTION: HIGH WIND" PORTFOLIO.

A. DEC: As shown in Table A-12 on page 184 of the DEC IRP, for the 70% CO_2 Reduction: High Wind portfolio, DEC retires 5,974 MW of coal and adds 7,478MW of incremental solar, 1,101 MW of onshore wind, 1,338 MW of offshore wind, 2,404 MW of incremental storage, and 4,076 MW of incremental gas resources. The high-level assessment conducted to determine the DEC transmission network upgrades needed to enable the interconnection of these new incremental resources resulted in an estimate of $1.7 billion needed for the upgrades.

DEP: As shown in Table A-12 on page 183 of the DEP IRP, for the 70% CO_2 Reduction: High Wind portfolio, DEP retires 3,208 MW of coal and adds 4,835 MW of incremental solar, 1,729 MW of onshore wind, 1,292 MW of offshore wind, 2,010 MW of incremental storage, and 2,138 MW of incremental gas resources. The high-level assessment conducted to determine the DEP transmission network upgrades needed to enable the interconnection of these new incremental resources resulted in an estimate of $4.6 billion needed for the upgrades. Estimates for the transmission network upgrades needed to import offshore wind energy were based on prior NCTPC assessments. An update of these NCTPC assessments is in progress and may result in materially different network upgrade costs.

Q. PLEASE DESCRIBE THE COST AND NATURE OF DEC's AND DEP's FUTURE TRANSMISSION PROJECTS TO FACILITATE THE "NO NEW GAS" PORTFOLIO.

A. DEC: As shown in Table A-12 on page 184 of the DEC IRP, for the 70% CO_2 Reduction: No New Gas portfolio, DEC retires 5,974 MW of coal and adds 7,478MW of incremental solar, 1,401 MW of onshore wind, 138 MW of offshore wind, 684 MW of small modular reactor (SMR) resource 2,406 MW of incremental storage, and 0 MW of incremental gas resources. The high-level assessment conducted to determine the DEC transmission network upgrades needed to enable the interconnection of these new incremental resources resulted in an estimate of $1.9 billion needed for the upgrades.

DEP: As shown in Table A-12 on page 183 of the DEP IRP, for the 70% CO_2 Reduction: High Wind portfolio, DEP retires 3,208 MW of coal and adds 4,985 MW of incremental solar, 1,729 MW of onshore wind, 2,492 MW of offshore wind, 5,011 MW of incremental storage, and 0 MW of incremental gas resources. The high-level assessment conducted to determine the DEP transmission network upgrades needed to enable the interconnection of these new incremental resources resulted in an estimate of $4.8 billion needed for the upgrades. Estimates for the transmission network upgrades needed to import offshore wind energy were based on prior NCTPC assessments. An update of these NCTPC assessments is in progress and may result in materially different network upgrade costs.

Q. PLEASE DESCRIBE THE COST AND NATURE OF DEC's AND DEP's FUTURE TRANSMISSION PROJECTS TO FACILITATE INCREASED IMPORT CAPABILITY.

A. The Companies conducted a high-level assessment to identify the number of transmission projects and estimated costs associated with increasing import capability into the DEC/DEP area transmission systems from all neighboring transmission regions as well as from offshore wind. The assessments considered the necessary new construction and upgrades needed to increase import capability by 5GW and l0GW respectively.

The 5GW import scenario would require on the DEC/DEP transmission systems alone:

- four (4) new 500kV lines,
- three (3) new 230kV lines,
- two (2) new 500/230kV substations,
- four (4) 300 MVAR SVCs, and
- several reconductor and lower class voltage upgrades.

The estimated costs for the associated transmission projects are between $4 billion and $5 billion.

The 1OGW import scenario would require on the DEC/DEP transmission systems alone:

- seven (7) new 500kV lines,
- four (4) new 230kV lines,
- three (3) new 500/230kV substations,
- four (4) 300 MVAR SVCs, and
- several reconductor and lower class voltage upgrades.

The estimated costs for the associated transmission projects are between $8 billion and $10 billion. These estimated costs do not include the cost of any neighboring system network upgrades necessary to facilitate importing a contracted resource into the DEC/DEP area transmission systems. Also, there are multiple risks with using off-system resources as designated network resources for capacity needed to meet planning reserve margins. These risks include, but are not limited to:

a. Delay in resource availability - if required transmission network upgrades on the DEC/DEP transmission system or neighboring transmission systems are delayed due to siting, permitting, or construction issues, these delays can jeopardize the scheduled in-service date of the transmission upgrades necessary for importing the capacity resource.

b. Loss of local ancillary benefits that are inherent with an on-system resource (e.g. Voltage/Reactive Support, Inertia/Frequency Response, AGC/Regulation for balancing renewable output) may require more on-system transmission upgrades such as adding SVCs for voltage support.

c. Curtailment due to transmission constraints in neighboring areas.

d. Transmission system stability issues under certain scenarios due to added distance between the capacity resource and load.

III. ADDITIONAL GRID INVESTMENT AND ASSUMPTIONS INCLUDED IN THE DEC AND DEP IRPs.

Q. PLEASE DESCRIBE OTHER GRID INVESTMENTS INCLUDED IN THE IRPs.

A. Grid-Connected Storage Systems: We have begun investing in grid-connected storage systems, with plans for multiple additional grid-connected storage systems. These systems will be dispersed throughout North and South Carolina service territories and could be located on property owned by the Companies or leased from their customers. These deployments will allow for a more complete evaluation of potential benefits to the distribution, transmission and generation system, while also providing actual operation and maintenance cost impacts of batteries deployed at a significant scale. Also, as directed by the NCUC, the Companies have been working with stakeholders to assess challenges and develop recommendations to address challenges related to retrofit of existing solar facilities with energy storage.[2] Finally, the Companies engaged Astrapé Consulting to perform a study to assess the incremental change in Effective Load Carrying Capability of battery storage as more batteries are added to the system. This study is further described in Chapter 6, Appendix H and Attachment IV. Witness Wintermantel from Astrapé discusses that study in his testimony.

IVVC: Integrated Voltage/VAR Control ("IVVC") is part of the proposed DEC Grid Improvement Plan ("GIP") and involves the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid. The IVVC program also aids in peak load reduction. The IVVC program is expected to be fully implemented in DEC by 2025. A detailed discussion of IVVC may be found on page 276 of the DEC IRP as well as in Appendix D to the DEC IRP. Table 3 below outlines the benefits of IVVC in the DEC service territory:

[2] *Joint Report by Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and Dominion Energy North Carolina on Storage Retrofit Stakeholder Meetings* , N.C.U.C. Docket No. E-100, Sub 158 (Sept. 16, 2020). Available at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=986fc1ea-8a59-4075-a528-ebaab6f564ed

Table 3

	ENERGY SAVINGS	CAPACITY SAVINGS	DER INTEGRATION
Value	**Loss Reduction**	**VAR Support**	**Grid Management**
Operational Benefit	▪ Lower voltage reduces distribution line losses ▪ Lower losses means a more efficient grid ▪ Reduced reactive power also improves grid efficiency	▪ Integrated control of capacitor banks reduces VAR output at the generator, improving generator efficiency ▪ Offsetting reactive power means less apparent load on the system	▪ Near real-time, optimized control of volt/VAR devices means rapid grid response to address intermittency
Customer Benefit	▪ Greater grid efficiency means less fuel consumed to make power	▪ Less peak load on the grid means reduced need to build additional peaking generation	▪ Rapid grid response means more ability to integrate Distributed Energy Resources (DER)
Environmental Benefit	▪ Less fuel consumption means **lower customer bills and lower carbon emissions**	▪ Fewer peaking plants means **reduced capacity costs passed on to customers**	▪ More integration of DERs means **reduced reliance on and emissions from fossil fuels**

Q. WHAT OTHER GRID-RELATED ASSUMPTIONS ARE INCLUDED IN THE DEC AND DEP IRPs?

A. We assume significant grid investment in all of the portfolios described in the IRPs. As described in the IRPs, the nation's electric delivery system design is more than 100 years old, and much of the equipment installed across the country has been in place for decades. The electric grid was designed to transport electricity from large centralized generation plants to customers, which has limitations in its capability to seamlessly integrate large amounts of renewable energy sources or fully leverage distributed resources, such as batteries at the local circuit level.

As DEC and DEP continue shifting away from traditional coal-fired generation sources as I described earlier in my testimony, the transmission and distribution grid infrastructure and associated control systems will need to transition to a more highly networked system capable of dynamically handling two-way power flows resulting from broader deployment of distributed energy resources and supporting new ways in which customers will consume energy. These trends coupled with significant increased utilization of variable renewable energy sources and retirement of resources that have historically provided critical voltage support and full dispatchability over long durations help highlight the challenges ahead for utilities to identify and develop the grid infrastructure and interconnected resources that can efficiently and reliably serve customers' energy needs while also supporting CO_2 reductions.

IV. STUDIES AND INPUT DERIVED FROM NCUC PROCEEDINGS

Q. PLEASE EXPLAIN THE NCUC REQUIREMENTS AS THEY RELATE TO GRID INVESTMENTS AND THE COMPANIES' 2020 IRPs.

A. In accepting the Companies' 2019 IRP updates, the NCUC directed the Companies that the "earliest practicable date" chose by the Companies when developing their alternative portfolio(s) and the replacement resources included in the portfolio(s) should reflect the transmission and distribution infrastructure investments that will be required to make a successful transition. The NCUC also directed the Companies to identify with as much specificity as possible all major transmission and distribution upgrades that will be required to support the alternative resource portfolios along with the best current estimate of costs of constructing and operating such upgrades.[3]

Q. HOW HAVE THESE NCUC DIRECTIVES INFLUENCED THE COMPANIES' 2020 IRPS?

A. With the NCUC request to identify all major transmission and distribution upgrades that will be required to support the alternative resource portfolios along with the best current estimate of costs of constructing and operating such upgrades, DEC and DEP were compelled to include cost estimates for transmission network upgrades that would be needed for integrating the resources identified in the DEC and DEP IRP portfolio scenarios. Thus, Chapter 7, Grid Requirements, was included in each 2020 IRP reflecting such cost estimates.

Q. DO YOU HAVE ANY ADDITIONAL INFORMATION TO SHARE?

A. Yes. While the costs identified in the IRPs are reasonable for general planning purposes, actual costs will depend on a host of factors including the precise timing, location and type of resources being added to the grid. During a resource selection and siting process the required transmission and distribution infrastructure will also be studied in much greater detail. It is not possible to precisely site long term generation additions as part of a long range plan like the IRPs. This makes precise estimates of transmission costs difficult to ascertain in the context of an IRP.

However, under any of the DEC or DEP IRP portfolio scenarios, transmission network upgrades and grid requirements as discussed in my testimony are vital to enabling

[3] *Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans*, at 9, N.C.U.C. Docket E-100, Sub 157 (April 6, 2020). Available at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=86f15be3-7617-4910-aeae-d8568c4d0983

the retirement of coal generation and integrating incremental resources, whether through external capacity purchase arrangements or interconnecting resources directly to the DEC and DEP grids. These network upgrades and grid requirements are necessary to support voltage and power flows that will ensure a reliable grid for providing critical electric service to DEC and DEP customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does.